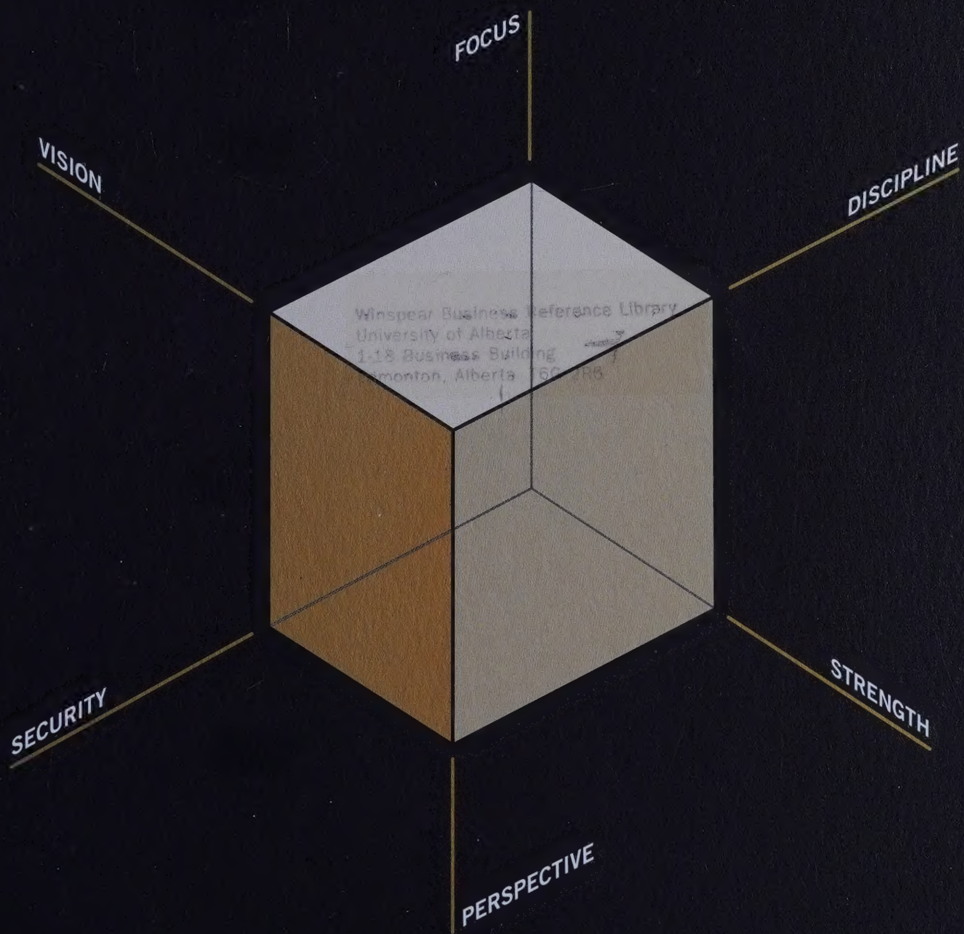


Real Resources Inc.
Annual Report 2002

Real Resources Inc. is a Calgary-based company active in the exploration, development and production of crude oil and natural gas in Western Canada. The Company has grown through exploration, development and strategic acquisitions.

Highlights

(In thousands of dollars, except where noted)

	2002	2001	% Change
Financial			
Production revenue	**52,554**	51,527	2
Cash flow from operations	**26,829**	27,578	(3)
Per share *(basic) ($/share)*	**1.36**	1.48	(8)
Per share *(diluted) ($/share)*	**1.34**	1.45	(8)
Net earnings	**5,907**	7,607	(22)
Per share *(basic) ($/share)*	**0.30**	0.41	(27)
Per share *(diluted) ($/share)*	**0.29**	0.40	(28)
Long-term debt *(net)*	**56,570**	32,689	73
Total assets	**163,346**	121,038	35
Shareholders' equity	**61,624**	53,787	15
Net capital expenditures	**54,270**	34,710	56
Average common shares outstanding *(000s)*	**19,716**	18,593	6
Operating			
Working interest production			
Crude oil and liquids *(bbls/d)*	**3,248**	2,603	25
Natural gas *(mcf/d)*	**9,148**	10,025	(9)
Total oil equivalent *(boe/d)*	**4,772**	4,274	12
Average prices			
Oil *($/bbl)*	**33.73**	34.08	(1)
Gas *($/mcf)*	**3.73**	5.13	(27)
Cash flow netback *($/boe)*	**15.44**	17.69	(13)
Operating costs *($/boe)*	**6.03**	5.81	4
General and administrative *($/boe)*	**1.64**	1.71	(4)
Wells drilled			
Gross	**114**	86	31
Net	**99.8**	53.2	88

TABLE OF CONTENTS

ABBREVIATIONS

bbls barrels
mbbls thousand barrels
bbl/d barrels of oil per day
mcf thousand cubic feet
mcf/d thousand cubic feet per day
mmcf million cubic feet
boe barrels of oil equivalent where natural gas is equated to oil using 6 mcf = 1 barrel of oil
boe/d barrels of oil equivalent per day
mboe thousand barrels of oil equivalent
NGL natural gas liquids

Our goal is to create growth and value for our shareholders over the long-term.

Left to right: Dale Cugnet – Controller, Frank Muller – V. P. Exploration, Pamela Orr – V. P. Finance & C.F.O. Lowell Jackson – President and C.E.O., Ken Murphy – Executive Vice President, Larry Green – Land Manager, Clay Curry – Field Superintendent.

Message to our Shareholders

Real has been transformed from a small oil weighted producer to a well balanced full-cycle oil and gas company. The depth of our prospect inventory, the diversity of our opportunities and our prudent approach to capital management and commodity hedging will continue to drive our growth.

In 2002, the Company established corporate records for wells drilled, reserve additions, production and revenue levels in our fourth consecutive year of growth.

Real was one of the industry's most active drillers during 2002. We drilled a record 114 wells, including 25 exploratory wells. This drilling resulted in the discovery of 22 oil/gas pools within our three core areas located in Alberta. Capital expenditures totaled $41.2 million (before acquisitions and dispositions), up 27% from 2001. Drilling represented $25.4 million or 62% of our total capital program. A record $7.7 million was invested in land and seismic. The Company purchased 40,826 net acres of undeveloped land at an average cost of $112 per acre. In addition, we shot 30 square miles of proprietary 3-D seismic and purchased 31 square miles of 3-D and 501 miles of 2-D trade seismic primarily in the Neutral Hills and Scandia areas. Our recent exploratory drilling successes and growing land and seismic inventories position Real for future growth.

Proved reserves increased 34% in 2002. Year-end reserves were independently evaluated at 15.8 million barrels of oil equivalent (boe) for proved reserves and 18.9 million boe for established reserves (proved plus half probable). Natural gas reserves comprised 46% of total proved reserves in 2002. The Company replaced 230% of 2002 production with proved reserves at an average cost of $9.42 per boe. Over the past three years, we have achieved a compounded annual reserve growth of 37%.

Daily production averaged 4,772 boe per day, 12% higher than in 2001 (5% higher on a per-share basis). These results contributed to a 24% compounded annual growth in production per share over the past three years. In the first half of 2002, our drilling program concentrated on oil projects in response to favourable oil prices. In the second half of the year, the focus turned to natural gas projects in light of improving gas economics. As the majority of our natural gas wells were drilled in the latter part of the year, the full impact of Real's natural gas focus is not reflected in our 2002 production results. Oil and natural gas liquids production rose 25% in 2002, while natural gas production was 9% lower. On a boe basis, commodity prices were down 8% in 2002 as compared to 2001. As a result, gross revenue increased by 2% while cash flow declined by 3% compared with the prior year. Net earnings were $5.9 million in 2002 versus $7.6 million in 2001.

OUR VISION

Our goal is to create growth and value for our shareholders over the long-term. We envision growing production to more than 10,000 boe per day within three to five years, split evenly between crude oil and natural gas. Our exploration and development strategy remains consistent and has proven successful. To complement internal prospect generation, we will continue to exploit opportunities to add strategic corporate and asset acquisitions in core areas. We manage and take advantage of commodity price cycles through a conservative hedging program and a flexible, counter-cyclical approach to project economics.

FULL-CYCLE EXPLORATION

We are continuing to build a full-cycle exploration program to generate growth for the long-term. Our team has a proven track record of internal prospect generation. We have been successful in assembling large land positions in focused geologic and geographic areas and we maintain control of our projects through high working interests and operatorship. Of the 114 wells drilled in 2002, our average working interest was 87%, including 73% for the 25 exploration wells drilled.

COMMODITY CYCLE MANAGEMENT

Our strategy from inception has been to grow our prospect inventory in key areas of interest. This inventory of opportunities is weighted towards light to medium grade crude oil and natural gas. Our strategic objective is to achieve and sustain an equal balance between crude oil and natural gas reserves and production. Maintaining a diverse inventory of opportunities allows Real to maximize the value of crude oil or natural gas projects as dictated by economic return. The depth and balance of the Company's prospect inventory was readily apparent in 2002, giving us the flexibility to switch focus between crude oil and natural gas projects as dictated by market conditions.

Four years ago, we developed a risk management policy for commodity prices. The cornerstone of this policy is our hedging program. Real actively hedges the prices of both crude oil and natural gas. This program is designed to guarantee sufficient cash flow to complete the Company's planned capital program without exceeding targeted debt to cash flow ratios. In addition, hedging locks in the minimum economics on projects undertaken by fixing a floor price on both crude oil and natural gas without giving up all the upside to higher prices. By ensuring that the capital program is preserved through periods of price swings, value is maintained not only by the minimum price established through hedging but also through growth in production and reserves.

Real continues to build a full-cycle exploration program to generate growth for the long-term.

COMMODITY PRICE ENVIRONMENT

The economic slowdown in North America coupled with a warmer than normal winter on the continent had a profound effect on natural gas prices in the first nine months of 2002. The average price received for natural gas deteriorated through that period and reached a five-year low during the summer months. Since the third quarter, natural gas prices have increased dramatically. Lower natural gas prices over the last 18 months limited the number of natural gas wells drilled, which has resulted in declining productivity of natural gas reserves in North America. Demand remains high and the outlook for natural gas prices in North America is positive.

In contrast, crude oil prices remained relatively stable throughout much of 2002, as OPEC was successful in restricting crude oil supply whenever prices fell below their prescribed target level, which equates to approximately $25.00 U.S. per barrel, West Texas Intermediate. However, oil prices rose to recent historic highs above $30.00 U.S. per barrel at year-end. Political strife in Venezuela, which severely reduced production from one of the world's major oil producing countries, combined with uncertainty surrounding military action against Iraq, and reduced crude oil inventories in the United States, the world's largest oil consumer, have all contributed to rising crude oil prices. Oil prices are expected to remain high until the political turmoil is stabilized, although, a rapid resolution of the conflict coupled with a dramatic decline in the demand for oil may lead to a sharp drop in crude oil prices.

FUTURE VALUE GENERATION

In Canada, the active merger and acquisition activity of the past few years has dramatically changed the corporate landscape of the oil and gas industry. A number of larger entities have been created and these larger companies may drill fewer wells than the individual companies from which they were created. Oil and gas royalty trusts have grown rapidly and now make up a significant portion of the industry. As these trusts distribute the majority of their cash flow, little drilling is undertaken and no exploration projects are pursued.

This lack of drilling bodes well for future natural gas prices and for exploration focused companies like Real. The only large reserves that can dampen strong natural gas prices are liquefied natural gas reserves transported to North America and/or natural gas from reservoirs discovered in northern Canada and Alaska. Both of these alternatives require the construction of major infrastructure to transport the gas to market, an undertaking that will take a number of years. Current estimates suggest that a minimum gas price of $5.00 Cdn per thousand cubic feet is required to economically justify these projects. As a result we expect a period of strong natural gas prices in the future.

For 2003, our capital budget is $50 million. Of this amount, $7.0 million will be spent on land, $5.0 million on seismic acquisition, $7.0 million on pipeline and facilities construction and $31.0 million on drilling. We plan to drill up to 130 wells, including 32 exploration wells in our core areas.

We have a large inventory of natural gas prospects and our goal in 2003 is to bring more of our natural gas reserves into production. Natural gas projects, towards which much of the Company's activities were directed in the last half of 2002, will continue to be a focus in 2003 and will make up approximately 65% of our capital program.

During 2003, we plan to proceed with the development of a number of oil pool discoveries made in 2002 at Neutral Hills, Enchant and Ferrybank. Real will monitor oil prices prior to the development of these discoveries and any new oil initiatives. The Company is utilizing an average oil price of $24.00 U.S. per barrel in 2003 as the economic basis for oil projects.

Real's strength lies in the quality of our dedicated staff. Though small in numbers, their expertise, commitment and enthusiasm are unmatched. This team is the foundation of the Company's future growth. I would like to express my deep appreciation for their continued efforts in the pursuit of creating value for the shareholders of the Company.

In closing, I would like to thank the Board of Directors for their guidance throughout the year and on their behalf, I thank you, our shareholders, for your confidence in Real, our people and our vision.

On behalf of the Board of Directors,

Lowell E. Jackson, P.Eng
PRESIDENT & CHIEF EXECUTIVE OFFICER
MARCH 24, 2003

In 2002, Real established corporate records for wells drilled, reserve additions, production and revenue levels in our fourth consecutive year of growth.

Statistical Review

RESERVES RECONCILIATION

Crude Oil and NGLS *(mbbls)*	Proved	Probable	Total
January 1, 2002, opening balance	6,655	2,385	9,040
Production	(1,187)	–	(1,187)
Revisions	(157)	(302)	(459)
Additions	2,553	845	3,398
Acquisitions	988	147	1,135
Property dispositions	(321)	(60)	(381)
December 31, 2002, closing balance	**8,531**	**3,015**	**11,546**

Natural Gas *(mmcf)*	Proved	Probable	Total
January 1, 2002, opening balance	30,830	14,427	45,257
Production	(3,354)	–	(3,354)
Revisions	(3,137)	(3,524)	(6,661)
Additions	16,055	6,887	22,942
Acquisitions	3,268	1,494	4,762
December 31, 2002, closing balance	**43,662**	**19,284**	**62,946**

Reserves by Property *(at December 31,2002)*

Crude Oil and NGLS *(mbbls)*	Proved	Probable	Total
Enchant	2,358	468	2,826
Neutral Hills	1,530	530	2,060
Sounding Lake	1,160	490	1,650
Rocanville	710	578	1,288
Consort	768	91	859
Alida West	572	103	675
Other Properties	1,433	755	2,188
Total	**8,531**	**3,015**	**11,546**

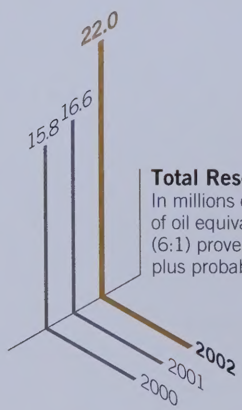
Natural Gas *(mmcf)*	Proved	Probable	Total
Atlee-Buffalo	14,872	4,403	19,275
Scandia	5,371	4,389	9,760
Ferrybank	5,245	1,719	6,964
West Provost	5,282	1,668	6,950
Enchant	3,665	1,518	5,183
Prairie River	1,753	2,012	3,765
Westerose	1,319	486	1,805
Other Properties	6,155	3,089	9,244
Total	**43,662**	**19,284**	**62,946**

PRESENT WORTH OF FUTURE CASH FLOW

($ Millions)	**December 31, 2002**			December 31, 2001			December 31, 2000		
Discount	**0%**	**10%**	**15%**	0%	10%	15%	0%	10%	15%
Proved	**224**	**147**	**127**	159	94	78	182	115	100
Probable	**83**	**40**	**31**	61	24	18	54	25	19
ARTC	**8**	**4**	**3**	6	3	3	7	4	3
Total	**315**	**191**	**161**	226	121	99	243	144	122

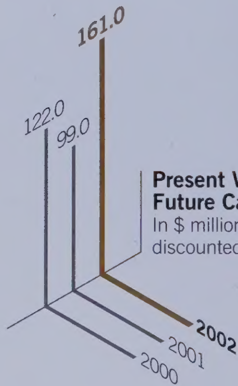
PRICING FORECAST

	West Texas Intermediate U.S. $/bbl			Edmonton Reference Price Cdn $/bbl			Corporate Average Natural Gas Price Cdn $/mcf		
December 31	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
2001	**–**	–	27.00	**–**	–	39.91	**–**	–	6.88
2002	**–**	21.00	24.00	**–**	32.31	34.80	**–**	3.40	5.04
2003	**26.00**	21.50	23.00	**38.96**	32.55	32.78	**5.25**	3.96	4.65
2004	**24.00**	21.93	23.00	**35.86**	32.68	32.27	**4.91**	4.16	4.28



Total Reserves
In millions of barrels of oil equivalent (6:1) proved plus probable

Reserves Additions
In millions of barrels of oil equivalent (6:1) including acquisitions, dispositions & revisions



Present Value of Future Cash Flow
In $ millions discounted at 15%

PRODUCTION BY AREA

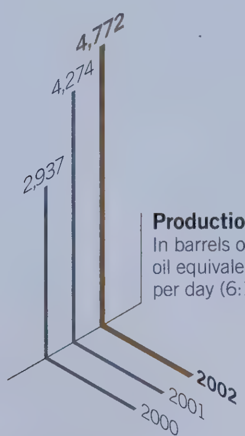
Crude Oil and NGLS *(bbl/d)*	**2002**	2001	2000
Neutral Hills	**1,141**	290	–
Hays/Enchant	**542**	425	195
Sounding Lake	**469**	578	647
Alida	**328**	501	668
Rocanville	**159**	171	158
Evi	**154**	173	166
West Provost	**93**	94	33
Minor Properties	**362**	371	293
Total	**3,248**	2,603	2,160

Natural Gas *(mcf/d)*			
Atlee Buffalo	**1,884**	1,825	595
West Provost	**1,304**	1,168	326
Ricinus	**1,072**	1,422	486
Scandia	**934**	1,138	232
Prairie River	**885**	406	–
Westerose	**759**	659	–
Nelson Lake	**427**	889	83
Virginia Hills	**339**	815	1,822
Minor Properties	**1,544**	1,703	1,114
Total	**9,148**	10,025	4,658

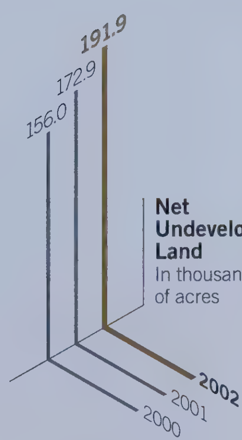
ACREAGE SUMMARY

	Total		Undeveloped		
December 31, 2002 *(acres)*	Gross	Net	Gross	Net	Fair Market Value*
Alberta	430,667	262,639	299,323	180,665	$ 11,621,340
Saskatchewan	26,724	13,126	23,622	10,835	438,157
Manitoba	413	413	413	413	2,318
Total	**457,804**	**267,178**	**323,358**	**191,913**	**$ 12,061,815**

* *Seaton-Jordan & Associates Ltd. – undeveloped lands only.*



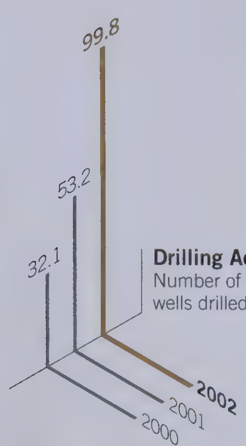
Production
In barrels of oil equivalent per day (6:1)



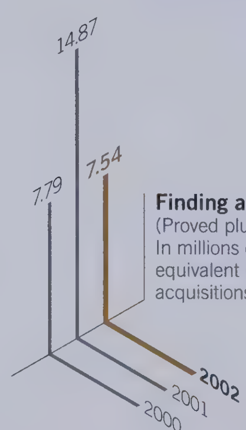
Net Undeveloped Land
In thousands of acres

DRILLING ACTIVITY

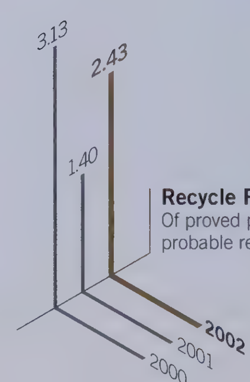
	2002		2001		2000	
	Gross	**Net**	Gross	Net	Gross	Net
Exploratory Wells						
Oil	**3**	**2.5**	2	2.0	3	2.5
Gas	**10**	**8.5**	14	9.9	14	8.9
Dry	**12**	**7.3**	16	7.2	10	5.8
Sub Total	**25**	**18.3**	32	19.1	27	17.2
Success Rate *(%)*	**52**	**60**	50	62	63	66
Average Working Interest *(%)*	**–**	**73**	–	68	–	64
Operated Wells	**18**	**–**	20	–	26	–
Development Wells						
Oil	**45**	**38.9**	31	18.7	8	6.5
Gas	**36**	**35.6**	21	14.0	8	6.6
Service	**–**	**–**	–	–	–	–
Dry	**8**	**7.0**	2	1.4	2	1.8
Sub Total	**89**	**81.5**	54	34.1	18	14.9
Success Rate *(%)*	**91**	**91**	96	96	89	88
Average Working Interest *(%)*	**–**	**91**	–	64	–	83
Operated Wells	**87**	**–**	31	–	16	–
Total Wells						
Oil	**48**	**41.4**	33	20.7	11	9.0
Gas	**46**	**44.1**	35	23.9	22	15.5
Service	**–**	**–**	–	–	–	–
Dry	**20**	**14.3**	18	8.6	12	7.6
Sub Total	**114**	**99.8**	86	53.2	45	32.1
Success Rate *(%)*	**82**	**86**	79	84	73	76
Average Working Interest *(%)*	**–**	**87**	–	62	–	71
Operated Wells	**105**	**–**	51	–	42	–



Drilling Activity
Number of net wells drilled



Finding and On-Stream Costs
(Proved plus probable)
In millions of barrels of oil equivalent (6:1) – Including acquisitions, dispositions & revisions



Recycle Ratio
Of proved plus probable reserves

FINDING AND ON-STREAM COSTS

Finding Costs *($ thousands)*	**2002**	2001	2000
Land	**4,408**	3,170	2,575
Seismic	**3,270**	1,883	1,849
Drilling and Completion	**25,386**	19,558	14,894
Acquisitions *(net of dispositions)*	**13,087**	2,331	32,165
Total finding costs	**46,151**	26,942	51,483
Facilities	**8,119**	7,768	3,646
Total on-stream costs	**54,270**	34,710	55,129

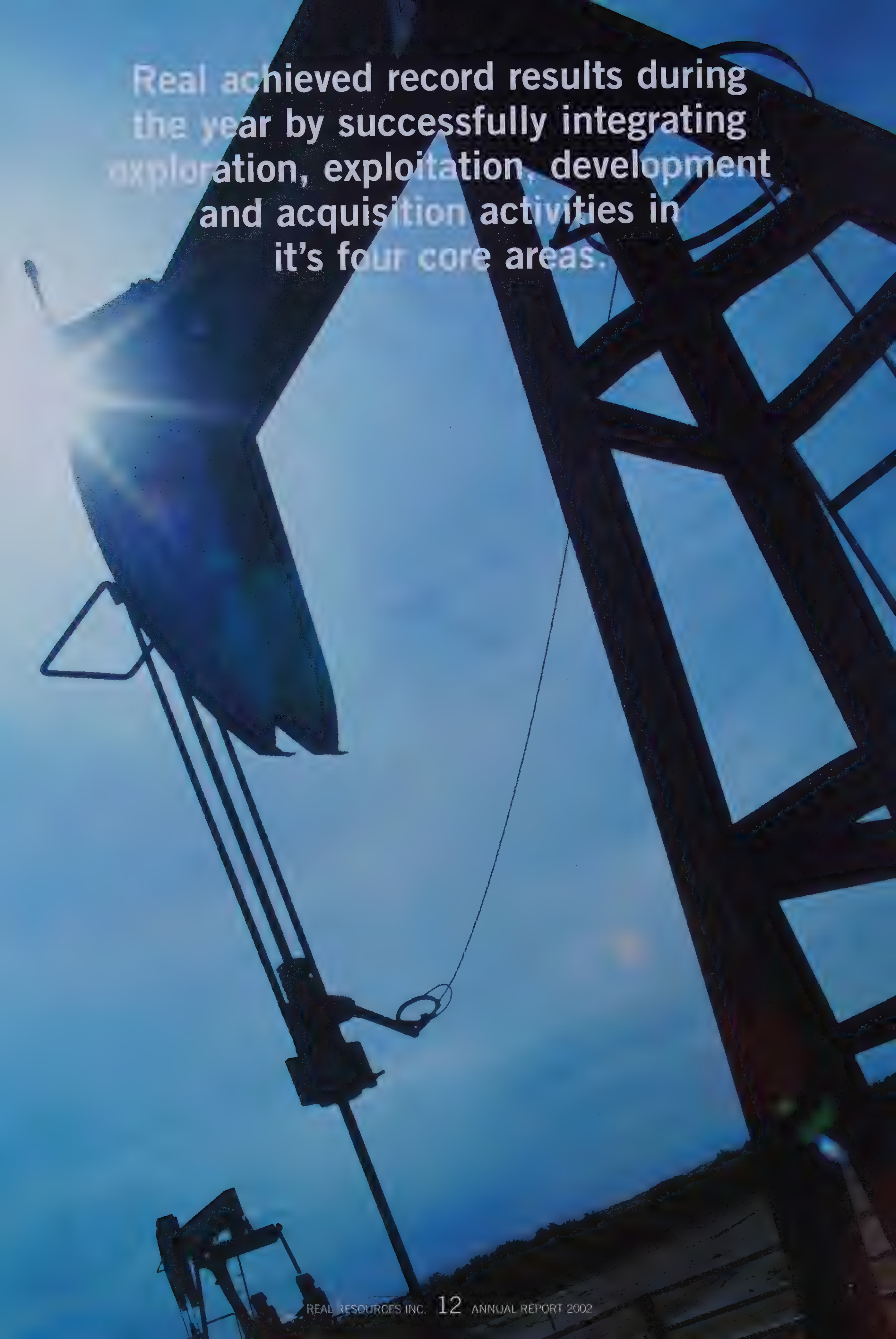
Reserve Additions *(mboe)(including acquisitions, dispositions & revisions)*			
Proved	**5,761**	1,820	6,472
Proved plus probable	**7,200**	2,334	7,074
Finding Cost per Unit *($/boe)*			
Proved	**8.01**	14.80	7.95
Proved plus probable	**6.41**	11.55	7.28
On-stream *($/boe)*			
Proved	**9.42**	19.07	8.52
Proved plus probable	**7.54**	14.87	7.79
Operating netback *($/boe)*	**18.34**	20.87	24.39

Recycle ratio			
Proved	**1.95**	1.09	2.86
Proved plus probable	**2.43**	1.40	3.13

Finding Costs *($ thousands)*	3-Year Average	5-Year Average
Land	3,384	2,046
Seismic	2,334	1,982
Drilling and Completion	19,946	14,872
Acquisitions *(net of dispositions)*	15,861	10,957
Total finding costs	41,525	29,857
Facilities	6,511	4,689
Total on-stream costs	48,036	34,546

Reserve Additions *(mboe) (including acquisitions, dispositions & revisions)*		
Proved	4,684	3,640
Proved plus probable	5,536	4,584
Finding Cost per Unit *($/boe)*		
Proved	8.87	8.20
Proved plus probable	7.50	6.51
On-stream *($/boe)*		
Proved	10.26	9.49
Proved plus probable	8.68	7.53
Operating netback *($/boe)*	21.20	17.53
Recycle ratio		
Proved	2.07	1.85
Proved plus probable	2.44	2.33

Real achieved record results during the year by successfully integrating exploration, exploitation, development and acquisition activities in it's four core areas.



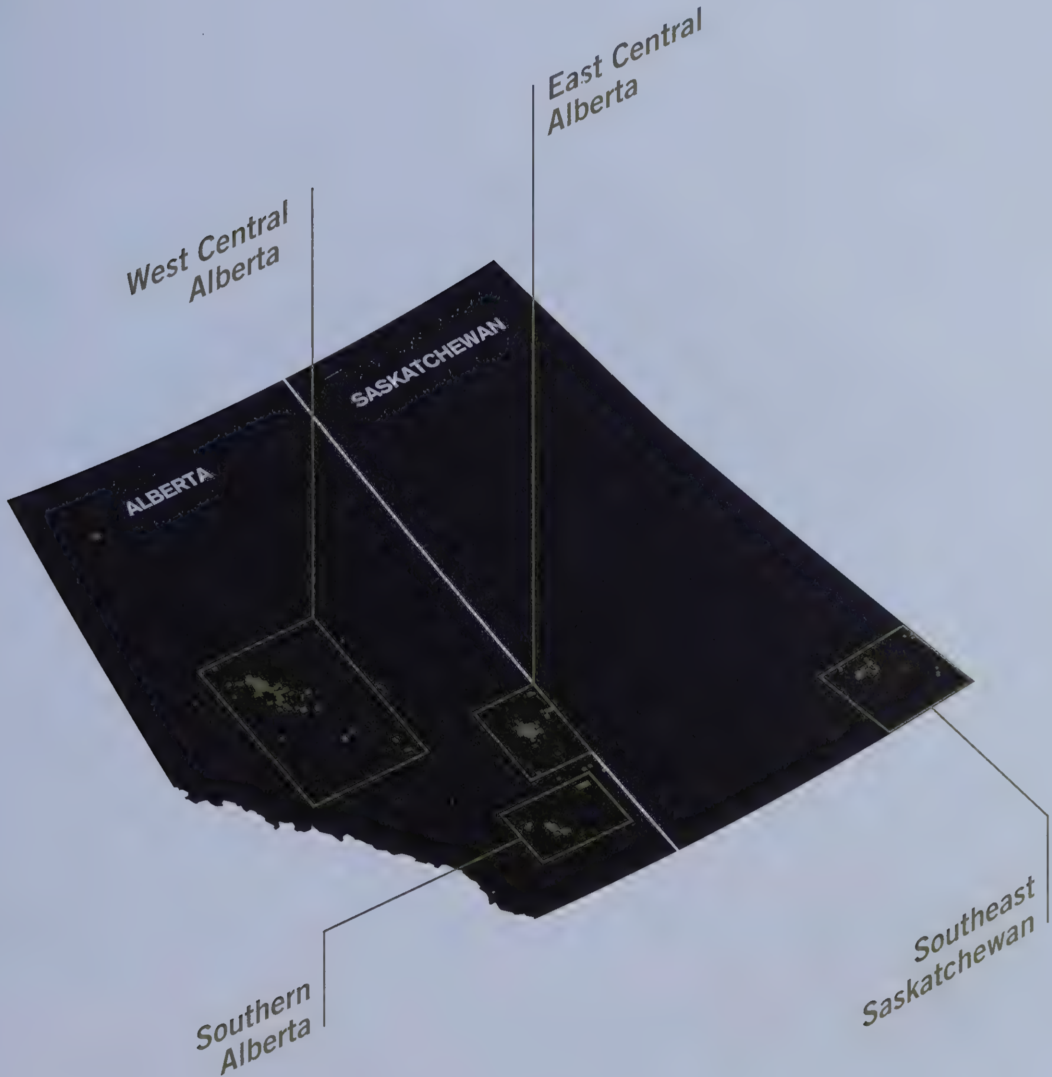
Review of Operations

EXPLORATION AND DEVELOPMENT

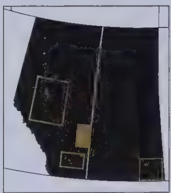
Our full-cycle exploration strategy continued to gain momentum in 2002, as the Company set another new record by drilling 114 wells (99.8 net), placing the Company in the top 25 most active drillers in Alberta. Real continued to maintain a prudent balance between exploration and development activities. Of the 114 wells drilled, 78% were development and 22% were exploratory.

Overall drilling success was maintained at 82%, while the average working interest per well increased significantly from 62% to 87%. We continued to place emphasis on hands-on management, operating 105 of the 114 wells.

We moved closer to our goal of maintaining an even split between the pursuit of oil and gas opportunities. During the year, the Company successfully drilled 48 oil wells (41.4 net) and 46 gas wells (44.1 net), along with 20 dry holes (14.3 net). This activity resulted in proved reserve additions of 2.6 million barrels of oil and liquids and 16.1 billion cubic feet of natural gas.



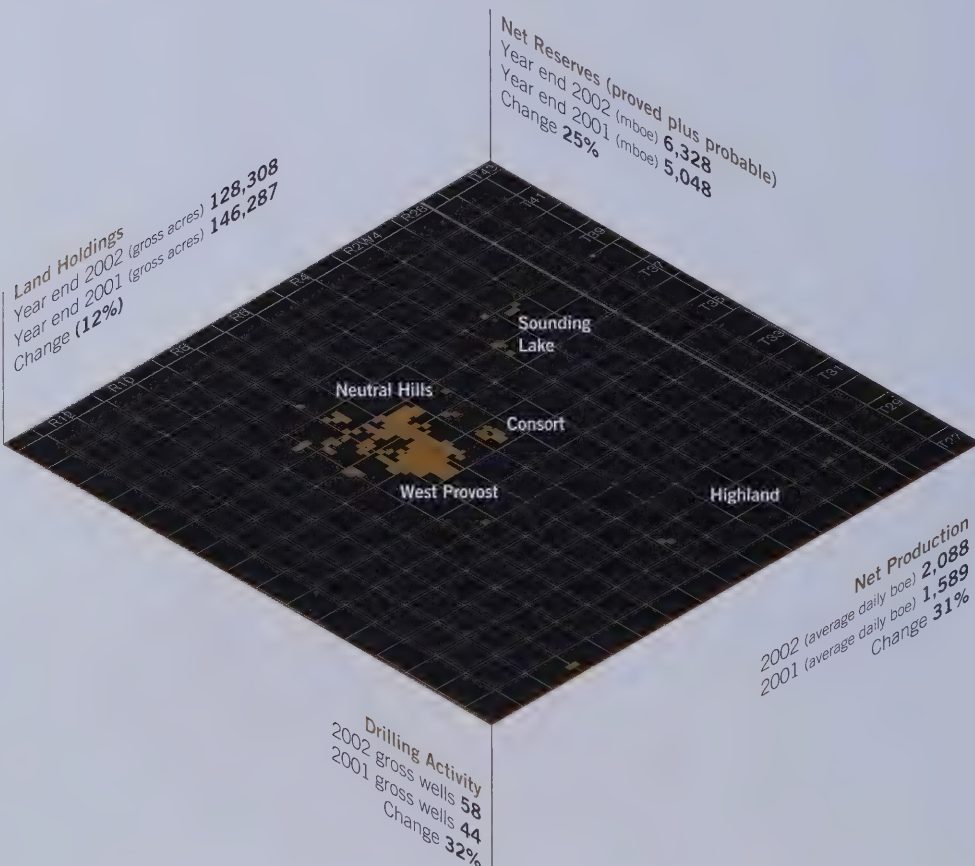
East Central Alberta



Just over half of Real's drilling and seismic activity in 2002 was in East Central Alberta where a total of 58 wells were drilled, including eight exploratory wells. The application of proprietary 3-D seismic has notably improved the overall success rate. The Company also successfully applied horizontal drilling technology to significantly reduce capital costs while increasing reserves and deliverability in the area, resulting in eight horizontal Dina oil wells.

At Neutral Hills, Real undertook full-scale development and delineation of its second significant Dina oil discovery made in 2001. The Company drilled 20 conventional wells (18.9 net), resulting in 17 oil wells (15.9 net), one gas well (1.0 net) and two dry holes (2.0 net). In addition, Real drilled five successful horizontal oil wells (5.0 net) into this pool.

Using the same formula for success, the Company also discovered a third significant new Dina oil discovery at Neutral Hills and drilled 10 oil wells (5.0 net) and two dry holes (1.0 net) to delineate the pool. Real has begun implementation of a water injection scheme in order to maintain reservoir pressure and performance.



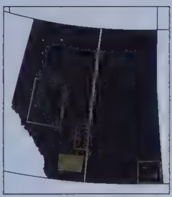
During the fourth quarter, Real acquired an abandoned Dina oil pool in the Neutral Hills area. Subsequent to year-end, the Company drilled three successful horizontal oil wells into this pool. Real plans to drill a further three horizontal wells into this pool in the first quarter of 2003.

Discoveries were also made in the greater Provost area during the year. A smaller two well Dina oil pool and a new Dina pool extension were discovered, which resulted in three oil wells – two vertical and one horizontal.

Five gas discoveries were made at Nelson Lake, Highland and in the West Provost Unit. An additional two oil discoveries were made at Sounding Lake and at West Provost. Four exploratory wells were dry and abandoned.

In 2003, we plan to spend $12.5 million on capital projects in East Central Alberta. Our emphasis will be on low-risk development activity, which will include drilling more than 40 wells. In addition, four to six exploration wells are planned.

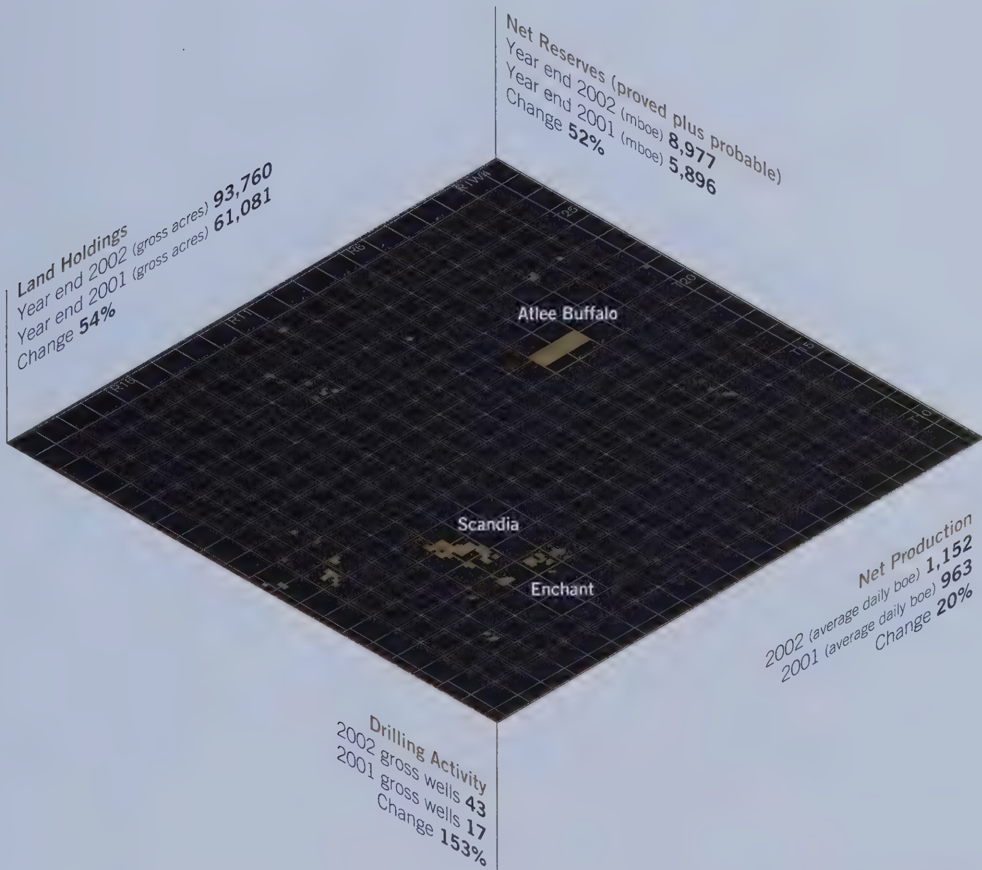
Southern Alberta



In Southern Alberta, Real accelerated its exploration and development program with the drilling of 43 wells in 2002.

On the Atlee Buffalo property, the Company drilled 30 successful Medicine Hat/Milk River wells in the fourth quarter in anticipation of higher gas prices. These wells represent the third well drilled per section and they are now on production. As many as six wells per section have been drilled on lands offsetting our property. Seven suspended wells were also put back on production by recompleting the Medicine Hat and completing the Milk River zones. Further drilling and re-completion activity is planned for this 100% owned 48-section block in 2003.

In the Hays/Enchant area, Real was able to increase its working interest from under 25% to 96% in a potential Arcs oil prospect. Utilizing geology and 3-D seismic, the Company proved its theory by drilling three Arcs oil wells. These wells have now been placed on production and have been flowing at a combined restricted rate of approximately 450 barrels of oil per day. A separate exploratory Arcs test well was dry and abandoned.

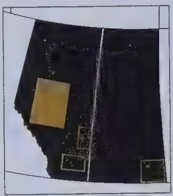


At Enchant West, the Company drilled an Arcs oil new pool discovery well. A second successful Arcs oil well was drilled to delineate the discovery in the fourth quarter. Further drilling is planned for 2003 pending continued sustainable production. Real has a 100% working interest in these two wells.

The Scandia property emerged as a core property in 2002. Real drilled six exploratory tests resulting in six (5.34 net) multi-zone oil and gas discovery wells. Using a combination of geology, 2-D trade data and proprietary 3-D seismic, the Company discovered a total of 11 new pools in these six wells. All wells are tied into facilities but are experiencing restricted rates due to third party facility processing constraints. Real is actively pursuing various processing alternatives and anticipates a resolution in the near future. The Company plans to drill six additional wells at Scandia in the first quarter of 2003, timed in anticipation of increased processing capacity for this gas.

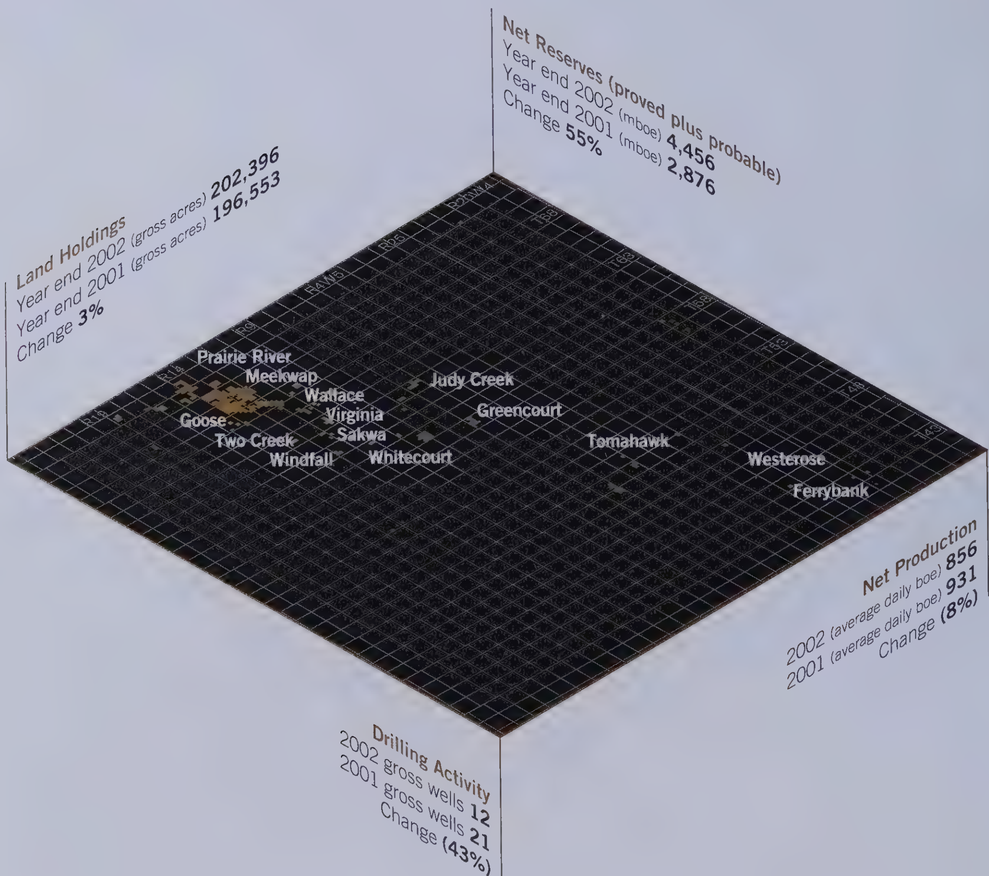
In 2003, we plan to spend $12.5 million in Southern Alberta. Our capital program includes drilling approximately 60 wells, including 12 exploration wells.

West Central Alberta



Real drilled a total of 12 exploration wells, the majority of which were characterized by higher risks and higher rewards. The Company continued in its philosophy to expose 10 to 15% of the capital budget to these projects.

At Ferrybank, two successful geological exploratory wells were drilled at 100% working interest. The first well encountered gas in multiple zones and is currently on production at approximately 1.5 million cubic feet per day with associated natural gas liquids. Downspacing of this section will allow for an additional two wells. The second well encountered gas and oil in two separate zones. The well is currently on production at 120 barrels of oil per day. Up to three additional wells are planned on this prospect for the first half of 2003.

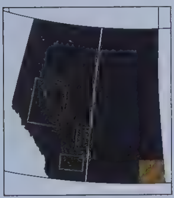


In the greater Swan Hills area, two Devonian test wells were drilled to depths of approximately 2,900 meters. At Sakwatamau, one well was drilled to test for the presence of an oil-bearing Swan Hills reef on 3-D seismic. Although the well was abandoned, further drilling is planned along the seismically defined trend. At Whitecourt, one well was drilled to test for a new gas-filled Swan Hills reef just south of Carson Creek. The well encountered a porous, but low permeability reef with virgin pressure and was abandoned. A 3-D seismic program will be shot in the first quarter of 2003 to determine the next location.

One well drilled at Thorsby (0.45 net) was cased for gas and is awaiting tie-in. The Company drilled unsuccessful wells at Economy Creek, Devil, Highvale and Girouxville East.

In 2003, we plan to spend $17.5 million in West Central Alberta. In keeping with our exploration focus in this area, 16 of the 24 wells planned will be exploratory.

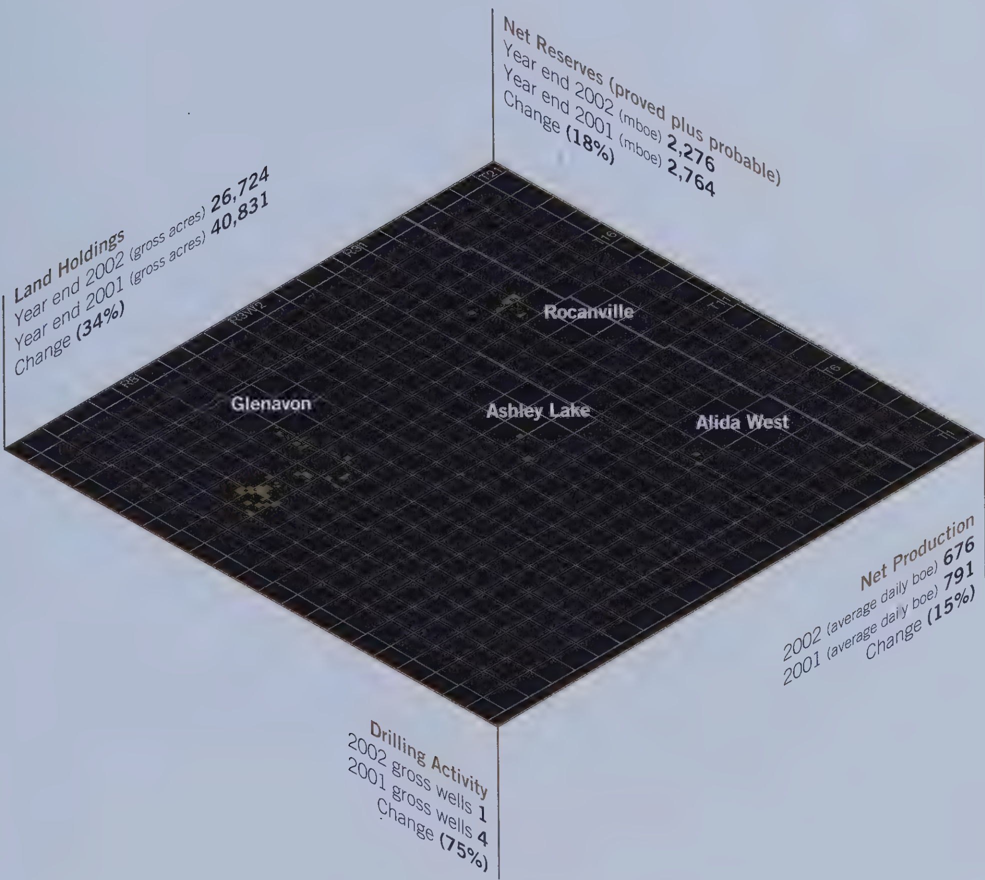
Southeast Saskatchewan



Real continues to hold a sizeable land position in Southeast Saskatchewan. The Company has scaled back activity due to the maturity of its properties.

At Ashley Lake, Real and its partner drilled a successful Tilston horizontal oil well in which the Company has a 33% working interest. This well represents the final development phase of this property.

During 2003, the Company will undertake a geological and geophysical review of its Rocanville property. Real plans to carry out additional 3-D seismic shooting which could lead to further development and/or exploitation drilling locations.



PRODUCT MARKETING

Real continues to diversify and enhance the Company's crude oil and natural gas market portfolio by utilizing the services and expertise of various oil and gas marketers to sell its production. Through this marketing strategy, the objective is to obtain product prices that are higher than industry average. Crude oil and natural gas liquids are sold under short-term contracts. Gas production is sold through a combination of purchasers with over 90% being sold at AECO spot market prices.

Real has maintained an active hedging program to manage the Company's exposure to foreign exchange, crude oil and natural gas price fluctuations. The intent of the hedging is to set an absolute foundation on product prices to ensure that a base capital program can be funded by a threshold cash flow without exceeding the corporate objective on the ratio of debt to cash flow. By providing for a base capital program, growth can be realized through increasing production and reserve volumes without compromising the balance sheet. The hedging is implemented utilizing a combination of price swaps, collars and floors. This approach allows for a secure minimum product price with the capability to participate in any upside. The time duration of the swaps, collars and floors are varied, which allows for price averaging over a long period of time.

CORPORATE GOVERNANCE

Real's Board of Directors is comprised of six senior business executives with extensive knowledge and experience in the oil and gas industry. Each Director has a vested interest in the Company through common share ownership and stock options. During 2002, there were five Board meetings, four Audit Committee meetings, two Compensation Committee meetings, three Reserve Audit Committee meetings and four Environmental Health and Safety Committee meetings. The Directors of the Company adhere to guidelines defined in The Toronto Stock Exchange Report on Corporate Governance. The Board is responsible for the stewardship of the Company, the strategies planning process, the Company's succession plan, and the Company's internal control and management information systems.

Of the six Board members, four are independent and unrelated, including the Chairman of the Board. Additionally, the Audit, Compensation and Reserve Audit Committees are comprised of non-management Directors. The Board as a whole does a self-assessment of its effectiveness annually. In addition, the Board as a whole evaluates the effectiveness of each committee and the contribution of individual directors. In assessing such matters, the Board conducts surveys of directors and makes recommendations for improvement. Further, the Board has placed a priority on good corporate governance practices and the Board as a whole develops the Company's approach to corporate governance issues, and regularly reviews the same.

On a minimum of an annual basis, the Board as a whole meets with management, separately from the budget process, to review and consider strategic planning. In addition, the Board reviews the strategic planning of the Corporation periodically in connection with regularly scheduled Board meetings and holds extra-ordinary strategic planning sessions based upon the need determined during the course of regularly scheduled Board meetings.

REPORT OF MANAGEMENT ON OIL & GAS RESERVES DISCLOSURES

Management of Real Resources Inc. are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. Such information includes reserves data, which are:

(a) (i) proved plus probable oil and gas reserves estimated as at December 31, 2002, using forecast prices and costs; and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserve quantities, estimated as at December 31, 2002, using constant prices and costs; and
(ii) the related standardized measure of discounted future net cash flows from oil and gas reserve quantities.

An independent qualified evaluator has evaluated the Company's reserves data. The report of the independent qualified evaluator will be filed with The Toronto Stock Exchange concurrently with this report.

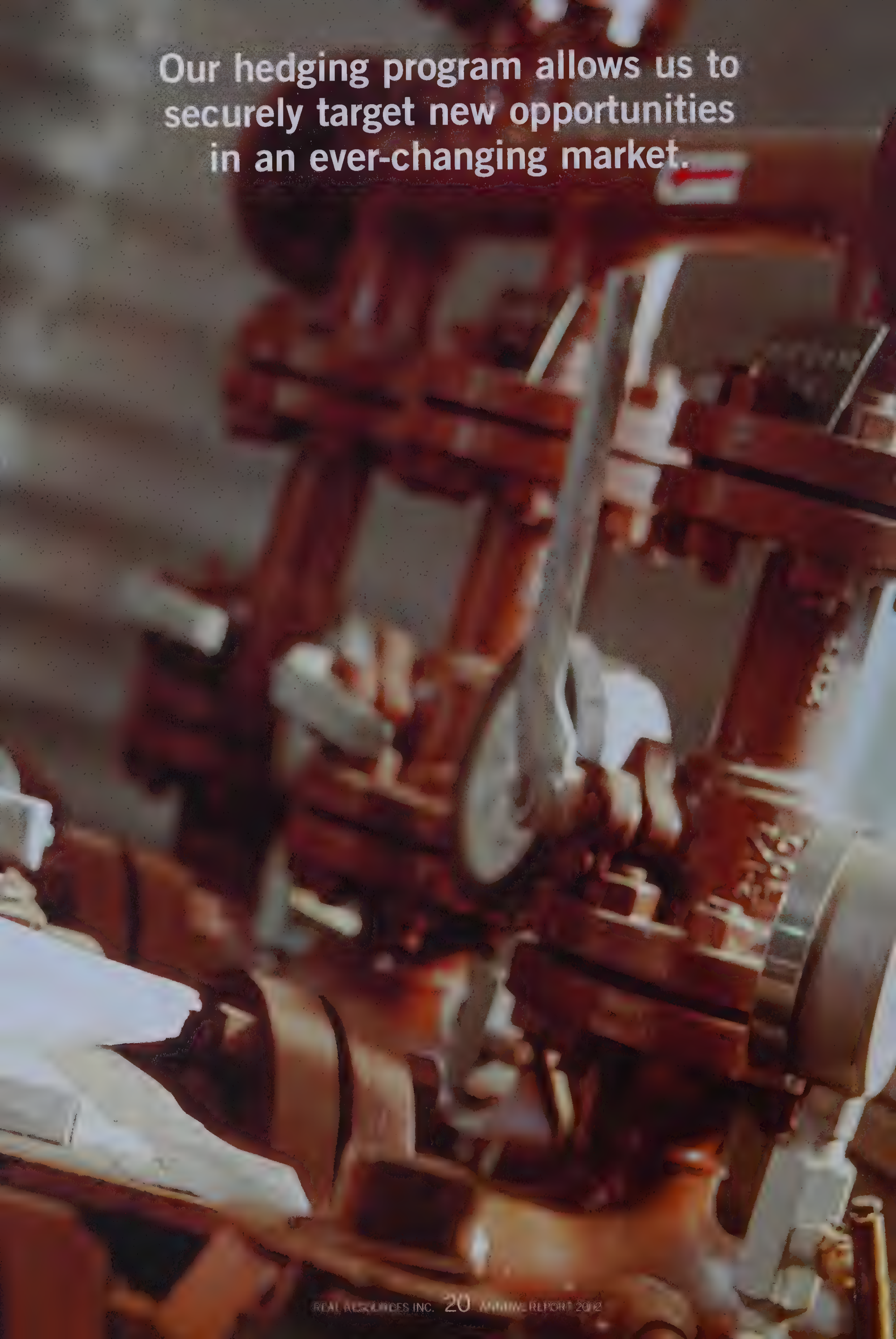
The Reserves Audit Committee of the Board of Directors of the Company has: (a) reviewed the Company's procedures for providing information to the independent qualified evaluator, (b) met with the independent qualified evaluator to determine whether any restrictions affected the ability of the independent qualified evaluator to report without reservation, and (c) reviewed the reserves data with management and the independent qualified evaluator.

The Reserves Audit Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserve Audit Committee, approved the content and filing of the reserves data and other oil and gas information, the filing of the report of the independent qualified evaluator on the reserves data and the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Lowell E. Jackson, P.Eng
PRESIDENT,
& CHIEF EXECUTIVE OFFICER

D. Nolan Blades, P.Eng
DIRECTOR,
RESERVE AUDIT COMMITTEE



Our hedging program allows us to securely target new opportunities in an ever-changing market.

Management's Discussion & Analysis

The following discussion and analysis is management's assessment of Real's historical financial and operating results and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2002 and 2001, together with the notes related thereto. The reader should be aware that historical results are not necessarily indicative of future performance. This discussion contains forward-looking statements that involve risks and uncertainties. Such information, although considered reasonable by Real at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made. Certain of the comparative figures have been restated to conform with the current year's presentation.

FINANCIAL HIGHLIGHTS OF 2002

The Company undertook a record drilling program in 2002. This program resulted in the fourth consecutive year of growth in production revenue and total production volumes. Until the end of the third quarter of 2002, the Company had focused its drilling activities towards oil targets, the results of which are reflected in average liquids production volumes during the year in excess of 3,200 barrels per day. During the fourth quarter of 2002, the Company oriented its drilling program towards natural gas prospects. This emphasis has successfully positioned the Company to benefit from the recovery of natural gas prices that started in the fourth quarter of 2002 and has continued into 2003.

DETAILED FINANCIAL ANALYSIS

Production Revenue Summary

	Years ended December 31		
($000s)	**2002**	2001	% Change
Oil and natural gas liquids revenue	**41,557**	30,830	35
Natural gas revenue	**12,887**	18,438	(30)
	54,444	49,268	11
Hedging gains/(losses)	**(1,993)**	1,870	(207)
Royalty income	**103**	389	(74)
Total oil and gas revenue	**52,554**	51,527	2

Production revenue in 2002 was $52.6 million, $1.1 million or 2% higher than the $51.5 million recorded in 2001. Additional production revenue of $7.6 million was attributable to the Company's higher average oil production. This was offset by lower realized gas prices and reduced average gas production levels.

Average daily oil and NGL production increased 25% to 3,248 barrels per day in 2002 from 2,603 barrels per day in 2001. These increased volumes came almost entirely from the successful Neutral Hills development program that started in 2001.

Natural gas production in 2002 decreased 9% to 9.1 million cubic feet per day from 10.0 million cubic feet per day in 2001. The benefits of the successful fourth quarter drilling program were not fully realized in 2002 due to facility constraints that the Company experienced in the Scandia area. The Company is actively pursuing alternative processing arrangements in this regard.

Total production for the year increased 12% to 4,772 barrels of oil equivalent per day in 2002 from 4,274 barrels of oil equivalent per day in 2001. The increase is net of the impact of the disposition of approximately 180 barrels of oil equivalent per day of mature production, the sale of which was closed in the fourth quarter.

The following table summarizes the commodity prices realized during 2002 and 2001. The average realized oil and NGL price received by the Company in 2002 was $33.73 per barrel, a 1% decrease from the $34.08 per barrel received in 2001. The Company's average realized natural gas price decreased 27% to $3.73 per thousand cubic feet in 2002 from $5.13 per thousand cubic feet in 2001.

Average Realized Price

	Years ended December 31		
	2002	2001	% Change
Oil and liquids *($/bbl, excluding hedging)*	**35.05**	32.45	8
Oil and liquids *($/bbl, including hedging)*	**33.73**	34.08	(1)
Natural gas *($/mcf, excluding hedging)*	**3.86**	5.04	(23)
Natural gas *($/mcf, including hedging)*	**3.73**	5.13	(27)
Total average realized price *($/boe, including hedging)*	**30.12**	32.78	(8)

Total Oil and Gas Revenue	Years ended December 31		
($/boe)	**2002**	2001	% Change
Sales revenue	**31.26**	31.58	(1)
Hedging gains/(losses)	**(1.14)**	1.20	(195)
	30.12	32.78	(8)
Royalty income	**0.05**	0.26	9
Total average realized price	**30.17**	33.04	(9)

The following table summarizes the impact on oil and gas revenue of the Company's production activities, prices and hedging activities.

Variance Analysis	**($ millions)**	% Change
Reported 2001 oil and gas revenue	51.5	
Increase due to oil and liquids production volumes	7.6	744
Decrease due to gas production volumes	(1.6)	(157)
Increase due to realized oil and liquids price	3.1	301
Decrease due to realized gas price	(3.9)	(384)
Impact of hedging activities (primarily oil)	(3.9)	(376)
Reduction due to royalty income	(0.2)	(28)
Total increase, net	1.1	100
Reported 2002 oil & gas revenue	52.6	

ROYALTY EXPENSE

Royalties increased marginally in 2002 to $10.1 million from $9.9 million in 2001. Royalties as a percentage of gross revenue decreased to 18.5% in 2002 from 20.2% in 2001. Royalties have declined on a percentage basis due primarily to the Company's increased proportionate activities in the Neutral Hills area that attract more favourable royalty treatment. The corresponding change in the composition of Crown versus non-Crown production has resulted in a lower overall average royalty burden.

Royalty Expense	Years ended December 31		
($000s, except where noted)	**2002**	2001	% Change
Crown	**7,103**	8,118	(13)
Freehold and GORR	**3,573**	2,409	48
Total royalties	**10,676**	10,527	1
ARTC	**(581)**	(600)	(3)
Total royalties, net of ARTC	**10,095**	9,927	2
Total royalties, net of ARTC *($/boe)*	**5.80**	6.36	(9)

Average Royalty Rates	Years ended December 31		
(% of sales, excluding hedging activities)	**2002**	2001	% Change
Crown	**13.0**	16.5	(21)
Freehold and GORR	**6.6**	4.9	35
Total royalties	**19.6**	21.4	(8)
ARTC	**(1.1)**	(1.2)	(8)
Total royalties, net of ARTC	**18.5**	20.2	(8)

OPERATING EXPENSES

Operating expenses in 2002 increased by 16% to $10.5 million from $9.1 million in 2001, primarily as a result of increased production volumes. Operating expenses on a unit of production basis increased to $6.03 per barrel of oil equivalent in 2002 from $5.81 per barrel of oil equivalent during 2001. Operating expenses during the fourth quarter of 2002 were unusually high due to major engine and compressor overhauls at West Provost and Atlee Buffalo as well as a variety of other costs associated with plant turnarounds that took place in the fourth quarter.

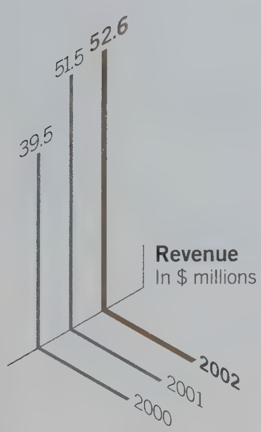
Operating Expenses	Years ended December 31		
($000s, except where noted)	**2002**	2001	% Change
Operating expenses	**10,498**	9,061	16
Operating expenses *($/boe)*	**6.03**	5.81	4

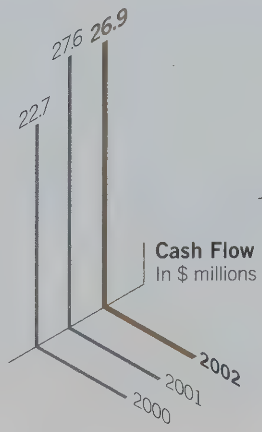
GENERAL AND ADMINISTRATIVE EXPENSES

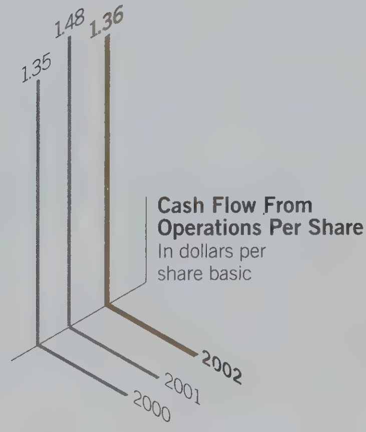
General and administrative expenses increased 7% to $2.9 million in 2002 compared to $2.7 million in 2001. This increase is attributable to the additional staffing levels required to support the Company's growth during the last 12 months. On a unit of production basis, general and administrative expenses decreased 4% to $1.64 per barrel of oil equivalent in 2002 from $1.71 per barrel of oil equivalent in 2001 due to administrative efficiencies associated with the Company's higher production levels.

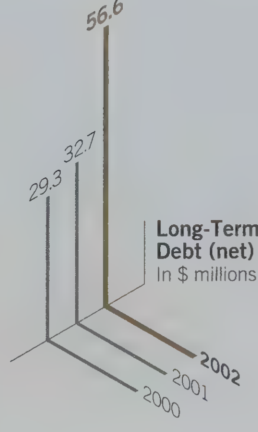
General and Administrative Expenses	Years ended December 31		
($000s)	**2002**	2001	% Change
Gross expense	**5,317**	4,737	12
Operator recoveries	**(1,439)**	(1,284)	12
Subtotal	**3,878**	3,453	12
Capitalized expense	**(1,023)**	(790)	29
Net expense	**2,855**	2,663	7

Average Cost per Barrel Equivalent	Years ended December 31		
($/boe)	**2002**	2001	% Change
Gross expense	**3.05**	3.04	–
Operator recoveries	**(0.83)**	(0.82)	1
Subtotal	**2.22**	2.22	–
Capitalized expense	**(0.58)**	(0.51)	14
Net expense	**1.64**	1.71	(4)









INTEREST EXPENSE

Interest expense for 2002 decreased 13% to $1.6 million from $1.8 million in 2001. Interest expense was $0.90 per barrel of oil equivalent, down 22% from $1.16 per barrel of oil equivalent in 2001. Interest expense dropped in 2002 despite a 14% increase in average debt levels due to the reduction in the bank's prime lending rate which is the main determining factor in the calculation of the Company's cost of debt. The increase in average debt outstanding reflects the use of bank debt to finance the capital expenditure program undertaken during the year.

Interest Expense	Years ended December 31		
($000s, except where noted)	**2002**	2001	% Change
Interest expense	**1,565**	1,808	(13)
Interest expense per boe *($/boe)*	**0.90**	1.16	(22)
Average debt outstanding	**36,100**	31,750	14
Average effective interest rate *(%)*	**4.3**	5.7	(25)

DEPLETION, DEPRECIATION AND SITE RESTORATION

Depletion, depreciation and site restoration expense ("DD&A") increased to $17.4 million in 2002 from $14.3 million in 2001, a 22% increase. Approximately 50% of the increase was directly due to increased production levels. Included in DD&A expense is $0.9 million attributable to the Company's site restoration provision which was slightly up from $0.8 million in 2001.

Depletion, Depreciation and Site Restoration	Years ended December 31		
($000s, except where noted)	**2002**	2001	% Change
Depletion, depreciation and site restoration	**17,408**	14,287	22
Depletion, depreciation and site restoration *($/boe)*	**9.99**	9.16	9

INCOME TAXES

The Company's current tax expense, which includes Large Corporation Tax and Saskatchewan Capital Tax, increased 27% to $0.6 million from $0.5 million in 2001. Current tax expense as a percentage of pre-tax income increased to 6% from 3.5% in 2001. The Large Corporation Tax was higher due to the additional debt undertaken in the fourth quarter of 2002 that was used to finance the Company's enhanced drilling program. Real paid no current income tax in 2002.

Future income taxes decreased 37% to $3.6 million from $5.7 million in 2001. This was primarily due to lower earnings before taxes. The decrease in the Alberta statutory rate in April 2002 was offset by the one time impact of adjustments made to the Company's 2002 opening pool balances that arose as a result of the finalization of a reassessment of balances brought forward from a corporate acquisition that was completed in previous years.

Income Taxes	Years ended December 31		
($000s, except where noted)	**2002**	2001	% Change
Capital taxes	**613**	482	27
Future income taxes	**3,613**	5,692	(37)
Total income taxes	**4,226**	6,174	(32)
Total income taxes *($/boe)*	**2.43**	3.96	(39)
Effective tax rate *(%)*	**41.7**	44.8	(7)

At the end of 2002 Real had approximately $74.8 million of accumulated tax pools that are available for deduction against future earnings compared to $55.1 million at December 31, 2001.

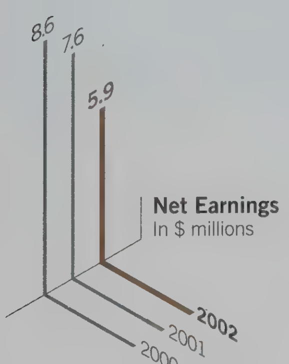
Summary of Tax Pools at December 31, 2002

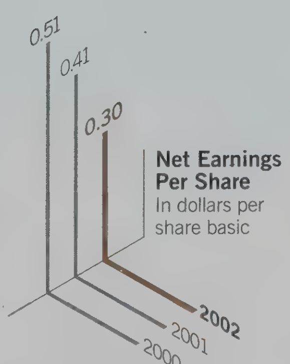
($000s)	Maximum Available Balance	Maximum Annual Deduction
Canadian Exploration Expense	**1,589**	100%
Canadian Development Expense	**22,423**	30%
Canadian Oil & Gas Property Expense	**28,258**	10%
Undepreciated Capital Cost	**21,516**	4-30%
Foreign Exploration & Development Expense	**478**	10%
Other	**489**	8-20%
Total	**74,753**	

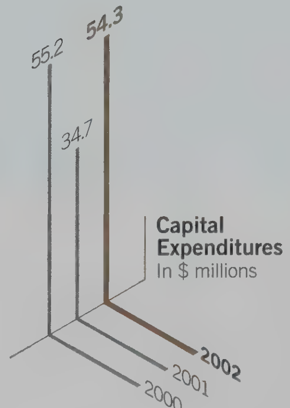
NET EARNINGS AND CASH FLOW FROM OPERATIONS

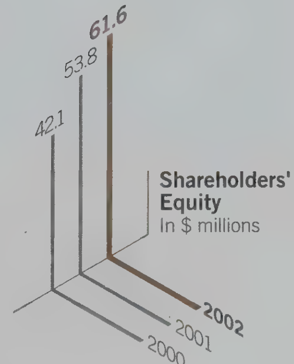
Net earnings decreased 22% to $5.9 million in 2002 from $7.6 million in 2001. Net earnings per share decreased 27% to $0.30 per share in 2002 from $0.41 per share in 2001. Similarly, diluted net earnings per share decreased 28% to $0.29 per share in 2002 from $0.40 per share in 2001. Cash flow from operations decreased 3% to $26.9 million in 2002 from $27.6 million in 2001. Cash flow from operations per share decreased 8% to $1.36 per share in 2002 from $1.48 per share in 2001. Diluted cash flow from operations decreased 8% to $1.34 per share from $1.45 per share.

Netbacks	Years ended December 31		
($/boe)	**2002**	2001	% Change
Production revenue	**30.17**	33.04	(9)
Net royalties	**(5.80)**	(6.36)	(9)
Operating expenses	**(6.03)**	(5.81)	4
Operating netback	**18.34**	20.87	(12)
General and administrative expenses	**(1.64)**	(1.71)	(4)
Interest expense	**(0.90)**	(1.16)	(22)
Current taxes	**(0.36)**	(0.31)	16
Cash flow netback	**15.44**	17.69	(13)
Depletion, depreciation and site restoration	**(9.99)**	(9.16)	9
Future income taxes	**(2.07)**	(3.65)	(43)
Corporate netback	**3.38**	4.88	(31)









LIQUIDITY AND CAPITAL RESOURCES

Real executes its growth strategy through exploration, exploitation and development activities supplemented with strategic property and corporate acquisitions. Net capital expenditures in 2002 were $54.3 million compared to $34.7 million in 2001. The corporate acquisitions of Belmont Energy Ltd. and Embo Petroleum Inc. were included in 2002 and 2001 capital expenditures respectively. These expenditures are summarized as follows:

Capital Expenditures

($000s)	**2002**	2001	% Change
Gross Property, Plant and Equipment, January 1	**161,866**	125,132	29
Exploration and Development Expenditures			
Lease acquisition	**4,408**	3,170	39
Geological and geophysical	**3,270**	1,883	74
Drilling and completion	**25,386**	19,558	30
Facilities and equipment	**8,057**	7,768	4
Total Exploration and Development Expenditures	**41,121**	32,379	27
Other expenditures	**62**	66	(6)
Total Capital Expenditures	**41,183**	32,445	27
Proceeds from property dispositions	**(4,366)**	(5,072)	(14)
Property acquisitions	**11,588**	4,323	168
Corporate acquisitions	**5,865**	3,014	95
Net capital expenditures before tax gross-up on acquisitions	**54,270**	34,710	56
Future income tax gross-up on corporate acquisitions	**2,646**	2,024	31
Net Capital Expenditures	**56,916**	36,734	55
Gross Property, Plant and Equipment, December 31	**218,782**	161,866	35

Funding for capital expenditures and acquisitions was provided by cash flow from operations, bank debt, property dispositions and working capital. Periodically, when conditions are favourable, the Company will undertake an equity issue to further fund its program.

At December 31, 2002, the Company had a $65.0 million financing commitment with a Canadian chartered bank which provided for an extendible revolving term credit facility. At the end of the year $53.7 million of the facility was drawn. Subsequent to the end of the year, the Company's bank undertook a borrowing base review and raised the facility to $71.0 million.

In addition to this debt, Real had a working capital deficiency of $2.9 million for a total net debt of $56.6 million. The ratio of total net debt as at December 31, 2002 to 2002 cash flow was 2.1 times. Net debt to 2002 cash flow (adjusted retroactively for the annualized impact of acquisitions and dispositions) was 1.9 times. Net debt at December 31, 2002, reflects the impact of an active fourth quarter drilling program. Net capital expenditures in this quarter amounted to $25.8 million. The full impact on cash flow from this activity level will not be entirely realized until 2003. Subsequent to year-end, the Company completed a common share equity offering of 3.1 million shares at a price of $4.95 per share for total gross proceeds of $15.3 million ($14.6 million net of expenses). This financing will be used to fund Real's ongoing drilling program as well as for general corporate purposes.

BUSINESS RISKS

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Real's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, and currency exchange rates. Operational risks include competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The Company minimizes its business risks by operating a large number of its properties. This enables Real to control the timing, direction and costs related to exploration and development opportunities. The geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. The Company closely follows all government regulations and has an up to date emergency response plan that has been communicated to all field operations by management. Real also carries insurance coverage to protect itself against potential losses. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk.

In 1994, the United Nations' Framework on Climate Change came into force and three years later led to the Kyoto Protocol which requires nations to reduce their emissions of carbon dioxide and, therefore, greenhouse gases. The Government of Canada has ratified the Kyoto Protocol. Reductions in greenhouse gases from producers in geographic areas where Real has operations may be required which could result in, among other things, increased operating and capital expenditures for those producers. This may make certain production of crude oil or natural gas by those producers uneconomic, resulting in reductions in such production. The Company is unable to predict the effect on the future earnings of Real as a result of the ratification of the Kyoto Protocol by the Government of Canada.

The Company is exposed to commodity price and market risk for its principal products of petroleum and natural gas. Commodity prices are influenced by a wide variety of factors of which most are beyond the control of Real. To manage this risk, the Company has entered into a number of short term financial derivatives for hedging purposes. These derivatives include contracts related to oil and gas prices, as well as foreign exchange rates. Real has also minimized its exposure to increased interest rates by entering into short term contracts for interest rate swaptions.

The Company is committed to maximizing shareholder value in an environmentally and socially responsible and safe manner. To this end, Real is actively involved in the Canadian Association of Petroleum Producers ("CAPP") Stewardship initiative. This voluntary initiative encourages members to continually improve their environment, health and safety performance and to report their progress to all stakeholders. The Company is pleased to report that CAPP has recognized Real's participation at a Silver level which acknowledges an open and transparent account of our environment, health and safety performance on a yearly basis and a leadership role in the improvement of these issues.

Consolidated Financial Statements and Notes

Auditors' Report

To the Shareholders of Real Resources Inc.

We have audited the consolidated balance sheets of Real Resources Inc. as at December 31, 2002 and 2001 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
CHARTERED ACCOUNTANTS

CALGARY, ALBERTA, CANADA
MARCH 7, 2003

Management's Report

To the Shareholders of Real Resources Inc.

The accompanying consolidated financial statements and all other financial information presented in this annual report are the responsibility of Real's management. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide for the safeguarding of assets and preparation of relevant, reliable and timely financial information.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee reviews these statements with management and the auditors and reports to the Board of Directors who approve the financial statements.

Pamela J. Orr, CA, CFA
VICE PRESIDENT FINANCE
& CHIEF FINANCIAL OFFICER

Lowell E. Jackson, P.Eng
PRESIDENT
& CHIEF EXECUTIVE OFFICER

CALGARY, ALBERTA, CANADA
MARCH 7, 2003

Consolidated Balance Sheets

December 31, 2002 and 2001
(In thousands of dollars)

	2002	2001
Assets		
Current Assets		
Accounts receivable	$ 8,629	$ 7,317
Prepaid expenses	1,061	479
	9,690	7,796
Property, plant and equipment *(note 4)*	153,656	113,242
	$ 163,346	$ 121,038
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 12,338	$ 10,228
Current portion of deferred revenue	222	220
	12,610	10,448
Long-term debt *(note 5)*	53,650	30,037
Deferred revenue	–	222
Accumulated future site restoration provision *(note 4)*	4,068	3,128
Future income taxes *(note 7)*	31,394	23,416
Shareholders' equity		
Share capital *(note 6)*	38,120	35,242
Retained earnings	23,504	18,545
	61,624	53,787
	$ 163,346	$ 121,038

Commitments *(note 8)*

See accompanying notes to consolidated financial statements.

On behalf of the board:

Robert B. Michaleski, CA
DIRECTOR

Martin G. Abbott, LLB
DIRECTOR

Consolidated Statements of Operations & Retained Earnings

Years ended December 31, 2002 and 2001

(In thousands of dollars, except per share amounts)

	2002	2001
Revenue		
Production revenue	$ 52,554	$ 51,527
Royalties, net of Alberta Royalty Tax Credit	(10,095)	(9,927)
	42,459	41,600
Expenses		
Operating	10,498	9,061
General and administrative	2,855	2,663
Interest on long-term debt	1,565	1,808
Depletion, depreciation and site restoration	17,408	14,287
	32,326	27,819
Earnings before taxes	10,133	13,781
Taxes *(note 7)*		
Current	613	482
Future	3,613	5,692
	4,226	6,174
Net earnings	5,907	7,607
Retained earnings, beginning of period	18,545	10,938
Acquisition of shares in excess of assigned value *(note 6 (f))*	(948)	–
Retained earnings, end of period	$ 23,504	$ 18,545
Earnings per share *(note 6 (i))*	$ 0.30	$ 0.41
Diluted earnings per share *(note 6 (i))*	$ 0.29	$ 0.40

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2002 and 2001

(In thousands of dollars, except per share amounts)

	2002	2001
Cash provided by (used in):		
Operating Activities		
Net earnings	**$ 5,907**	$ 7,607
Items not involving cash		
Depletion, depreciation and site restoration	**17,408**	14,287
Future income taxes *(note 7)*	**3,613**	5,692
Site restoration and abandonment expenditures	**(99)**	(8)
Cash flow from operations	**26,829**	27,578
Changes in non-cash working capital:		
Decrease (increase) in trade and other receivables	**(195)**	1,341
Increase in prepaid expenses	**(560)**	(55)
Decrease in trade and other payables	**(988)**	(219)
	25,086	28,645
Financing Activities		
Issue of share capital on exercise of stock options	**818**	189
Issue of flow-through shares *(note 6 (e))*	**–**	3,773
Repurchase of shares *(note 6 (f))*	**(1,718)**	–
Increase in long-term debt	**22,484**	7,312
Decrease in prepaid revenue	**(220)**	(257)
	21,364	11,017
Investing Activities		
Additions to capital assets	**(41,184)**	(32,445)
Corporate acquisitions *(note 3)*	**(131)**	(2,888)
Property acquisitions	**(11,588)**	(4,323)
Proceeds on property dispositions	**4,366**	5,072
	(48,537)	(34,584)
Changes in non-cash working capital:		
Decrease (increase) in trade and other receivables	**(726)**	630
Increase (decrease) in trade and other payables	**2,813**	(5,825)
	(46,450)	(39,779)
Change in cash	**–**	(117)
Cash, beginning of period	**–**	117
Cash, end of period	**$ –**	$ –
Cash flow from operations per share *(note 6 (i))*	**$ 1.36**	$ 1.48
Diluted cash flow from operations per share *(note 6 (i))*	**$ 1.34**	$ 1.45
Supplementary disclosure:		
Cash interest paid	**$ 1,494**	$ 1,812
Capital taxes paid	**579**	503

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2002 and 2001

(Tabular amounts in thousands of dollars, unless otherwise noted)

1. CORPORATE STRUCTURE

On October 31, 2002, the Company formed a wholly-owned subsidiary, Real Oil Corporation, incorporated under the ABCA, which changed its name to Real Oil & Gas Corp. ("Real Oil") on November 14, 2002.

Effective December 10, 2002, the Company acquired all of the issued and outstanding shares of Belmont Energy Ltd. ("Belmont"), a private Alberta oil and gas exploration and development company (note 3).

On December 17, 2002, the Company and its subsidiaries, Real Oil and Belmont (collectively the "Partners"), entered into a general partnership under the laws of Alberta (the "Partnership") to carry on business under the name Real Resources. Each partner agreed to contribute to the capital of the Partnership all of the properties, assets, interests and rights (with certain specified exclusions) relating to the petroleum and natural gas exploration, development, production and marketing business carried on by each (note 10 (a)).

2. ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and its partnership. Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(B) PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for exploration and development expenditures whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized. Such costs include lease acquisition, geological and geophysical, lease rentals on undeveloped properties, drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities. Proceeds received from disposals of properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20%, in which case a gain or loss on disposal is recorded.

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs (net of salvage value), and estimated costs of future development of proven undeveloped reserves are depleted and depreciated by the unit of production method based on estimated gross proven reserves as determined by independent engineers. Oil and gas reserves are converted to equivalent units using their estimated relative energy content.

Depreciation of property, plant and equipment not related to oil and gas properties is provided using the diminishing balance method at rates between 20 and 30%.

Costs of unproved properties are initially excluded from oil and gas properties for the purpose of calculating depletion. These unproved properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company carries its petroleum and natural gas properties at the lower of the capitalized cost and net recoverable value (the "ceiling test"). The net capitalized cost of each of the Company's assets is calculated as the net book value of the related assets less the accumulated provision for future income taxes and future site restoration. Net recoverable value is limited to the sum of future net revenues from proved properties and the cost of unproved properties (net of provisions for impairment) less estimated future financing and administrative expenses and income tax. Future net revenues are based on prices and costs prevailing at year-end.

(C) FUTURE SITE RESTORATION

Estimated future site restoration costs for oil and gas properties are provided for over the life of the proven reserves on a unit of production basis. Costs are based on the Company's engineering estimates considering current regulations, costs, technology and industry standards. Actual site restoration expenditures are charged against the accumulated future site restoration provision.

(D) DERIVATIVE FINANCIAL INSTRUMENTS

The Company uses various derivative financial instruments to manage its commodity price, foreign exchange and interest rate exposures. The Company does not use these instruments for trading purposes.

The Company's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified liability or specific firm transaction. Consequently, the Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the terms of the instrument all match the terms of the liability or transaction being hedged.

The Company's derivative financial instruments include commodity price instruments, foreign exchange contracts and interest rate swaps. All derivative financial instruments are accounted for using the accrual method. The gains or losses on these contracts are included in revenue and interest expense at the time of settlement.

(E) INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, the company records future income taxes for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantially enacted on the balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

(F) STOCK BASED COMPENSATION PLAN

Consideration paid by employees or directors on the exercise of stock options under the employee stock option plan is recorded as share capital. No compensation expense is recorded either on the granting or exercise of options under the plan.

3. ACQUISITIONS

The Company completed the following acquisitions during 2002 and 2001. These acquisitions have been accounted for by the purchase method, and accordingly, the respective results of operations have been included in these financial statements from the date of acquisition.

(A) ACQUISITION OF BELMONT ENERGY LTD.

Effective December 10, 2002, the Company acquired all of the issued and outstanding shares of Belmont Energy Ltd,. an oil and gas company. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

Non-cash working capital	149
Property, plant and equipment	8,510
Capital lease obligation	(70)
Long-term debt	(1,129)
Accumulated site restoration provision	(133)
Future income taxes	(2,646)
Total consideration	4,681

Consideration was comprised of: Issue of 900,000 common shares at $4.55 per share	4,095
Holdback amount – 100,000 common shares at $4.55 per share	455
Cash	131
Total consideration	4,681

The consideration paid by the Company was an aggregate of 1.0 million common shares (excluding transaction costs and subject to post closing adjustments) at a deemed aggregate total value of $4.6 million. The value of the shares issued for the Belmont Energy Ltd. acquisition was based on the closing price of the Company's shares on November 28, 2002, the day the transaction was finalized.

At closing, the Company delivered 0.9 million common shares to the former holders of the Belmont shares and reserved for issuance, but has not yet issued, 0.1 million common shares. The reserved shares have a deemed value of $0.5 million and have been reflected by the Company as a Holdback amount ("holdback").

Subsequent to the determination of any closing adjustments that are in excess of a predetermined threshold, the former holders of Belmont shares will receive a corresponding number of common shares of the Company, first by issuing the common shares reserved as the holdback and then, if necessary, issuing additional common shares from treasury.

(B) ACQUISITION OF EMBO PETROLEUM INC.

Effective March 1, 2001, the Company acquired all of the issued and outstanding shares of Embo Petroleum Inc., an oil and gas company, for cash.

Non-cash working capital (deficit)	(115)
Property, plant and equipment	5,037
Accumulated site restoration provision	(10)
Future income taxes	(2,024)
Total cash consideration	2,888

4. PROPERTY, PLANT AND EQUIPMENT

	2002	2001
Oil and gas properties, plant and equipment	**218,209**	161,412
Other	**573**	454
	218,782	161,866
Less accumulated depletion and depreciation	**65,126**	48,624
	153,656	113,242

At December 31, 2002, oil and gas properties included $9.4 million (2001: $10.5 million) relating to unproved properties which have been excluded from the depletion and depreciation calculation. Future development costs on proven undeveloped reserves of $7.8 million (2001: $8.9 million) are included in the depletion and depreciation calculation.

In 2002, the Company capitalized $1.0 million (2001: $0.8 million) of overhead directly related to exploration and development activities.

At December 31, 2002, the Company estimates its liability for future site restoration and abandonment to be $5.7 million (net of the year-end accumulated provision) (2001: $6.9 million).

5. LONG-TERM DEBT

At December 31, 2002 the Company had a $65 million financing commitment with a Canadian chartered bank which provided for an extendible revolving term credit facility and a U.S. $15 million swap facility. The credit facility revolves and fluctuates at the Company's option for a maximum of 364 days after the date of the bank's consent. If the revolving facility is not renewed at the end of the current revolving phase, the facility moves into the term phase whereby the credit facility will be permanently reduced by one payment on the 366th day following the last day of the revolving phase, which is the maturity date, in an amount equal to the outstanding principal. The credit facility provides that advances may be made by way of direct advances, bankers' acceptances or U.S. dollar LIBOR advances which bear interest at prevailing bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or the bank's prime lending rate depending on the nature of the advance. The authorized limit is subject to an annual review and re-determination of the Company's borrowing base by the bank.

Collateral pledged for the facility consists of a fixed and floating charge demand debenture in the principal amount of $150 million conveying a floating charge on all of the property and assets of the Company.

At December 31, 2002, all of the long-term debt was floating rate debt. The Company has entered into the following interest rate contracts, subject to cancellation periodically at the Company's option, to fix the interest on a portion of its long-term debt (note 9). These contracts were entered into to manage interest rate exposure. The interest rates shown are before bank fees.

Swaptions*

Principal amount	**Interest Rate**	**Term**
Cdn $10.0 million	3.00%	September 24, 2002 to March 24, 2003
Cdn $20.0 million	3.42%	April 1, 2003 to March 31, 2004

**Subject to cancellation quarterly at the Company's option.*

The effective interest rate on the amounts outstanding under the facility at December 31, 2002, was 4.1% (2001: 3.6%).

Subsequent to December 31, 2002, there was a re-determination of the borrowing base which provided for an increase in the Company's extendible revolving term credit facility to $71 million.

6. SHARE CAPITAL

(A) AUTHORIZED

Unlimited number of voting common shares without par value.
Unlimited number of first, second, third and fourth class preferred shares, issuable in series.

(B) COMMON SHARES ISSUED

	2002		2001	
	Number of Shares *(000s)*	**Amount**	Number of Shares *(000s)*	Amount
Balance at beginning of year	**19,584**	**35,242**	18,474	31,182
Exercised stock options	**345**	**858**	110	189
On acquisition of Belmont Energy *(c)*	**1,000**	**4,550**	–	–
Flow-through share issue *(e)*	**–**	**–**	1,000	4,000
Repurchase of common shares *(f)*	**(422)**	**(770)**	–	–
Share issue costs (net of tax effect)		**(40)**		(129)
Tax benefits renounced *(e)*		**(1,720)**		–
Balance at end of year	**20,507**	**38,120**	19,584	35,242

(C) At closing the Company delivered 0.9 million common shares to the former holders of the Belmont shares and reserved for issuance, but has not yet issued, 0.1 million common shares (note 3 (a)).

(D) STOCK BASED COMPENSATION PLAN

The Company has a stock option plan that provides for the issuance of options to its directors, officers and employees to acquire up to 1.8 million common shares. The options typically vest evenly over a three-year period and expire five years from the date of grant. The Company accounts for its stock based compensation using the intrinsic value method, whereby no compensation costs have been recorded in the financial statements for stock options granted. Consideration paid by employees on the exercise of stock options and purchase of stock is credited to share capital. Had the Company adopted the fair value based method of accounting, the compensation costs, along with the pro forma net earnings and pro forma net earnings per share for the Company would be as follows:

	2002
Stock based compensation costs	**271**
Net earnings attributable to common shareholders	
As reported	**5,907**
Pro forma	**5,636**
Net earnings per common share attributable to common shareholders	
Basic	
As reported *($/share)*	**0.30**
Pro forma *($/share)*	**0.29**
Diluted	
As reported *($/share)*	**0.29**
Pro forma *($/share)*	**0.28**

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2002. The fair value of each option granted is estimated on the date of grant using the Black–Scholes options pricing model with the following weighted average assumptions:

	2002
Fair value of options granted *($/share)*	**1.43**
Risk-free interest rate *(%)*	**4.2**
Expected life *(years)*	**3.4**
Expected volatility *(%)*	**43**
Expected dividend yield *(%)*	**–**

(E) FLOW-THROUGH SHARES

Certain oil and gas exploration activities have been financed from the 2001 share issuance of one million flow-through shares for gross proceeds of $4.0 million ($3.8 million net of expenses). The expenditures that were renounced to the purchasers of these shares were incurred in 2002 and accordingly, share capital has been reduced by the amount of the tax benefits associated with these expenditures. The corresponding future tax liability has also been recognized in the current year.

(F) NORMAL COURSE ISSUER BID

On June 17, 2002, the Company announced its intention to make a Normal Course Issuer Bid (the "Bid") through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 950,000 common shares of the Company, which represented approximately 5% of the Company's issued and outstanding common shares. The Bid commenced on June 19, 2002, and will terminate on June 18, 2003. The excess cost over book value of the shares purchased prior to December 31, 2002, was applied to Retained Earnings.

As at March 3, 2003, the Company had purchased 722,800 common shares for a total cost of $3.2 million.

(G) STOCK BASED COMPENSATION

A summary of the status of the Company's stock option plan as of December 31, 2002 and 2001, and changes during the years ended on those dates is presented below:

	2002		2001	
	Number of Options *(000s)*	**Weighted Average Exercise Price** *($/share)*	Number of Options *(000s)*	Weighted Average Exercise Price *($/share)*
Balance, beginning of year	**1,720**	**2.72**	1,599	2.59
Granted	**586**	**3.94**	395	3.33
Exercised	**(345)**	**2.48**	(110)	1.72
Expired/Cancelled	**(175)**	**3.01**	(164)	3.59
Balance, end of year	**1,786**	**3.14**	1,720	2.72
Exercisable at end of year	**974**	**2.63**	884	2.60

The following table summarizes information regarding stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding *(000s)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($/share)*	Number Exercisable *(000s)*	Weighted Average Exercise Price *($/share)*
$1.32 – $1.44	76	1.9	1.44	76	1.44
$1.60 – $1.92	380	1.0	1.67	367	1.66
$2.95 – $3.48	660	3.4	3.31	308	3.26
$3.52 – $3.60	172	0.3	3.59	167	3.60
$3.70 – $4.20	318	4.4	3.89	6	3.96
$4.40 – $4.80	180	3.7	4.62	50	4.40
	1,786	2.7	3.14	974	2.63

Subsequent to year end, the Company granted options to purchase 24,000 common shares at $5.10 per share which expire in the first quarter of 2008. Also subsequent to year end, options with respect to 267,000 shares were exercised at a weighted average price of $2.99 per share.

(H) WARRANTS

At December 31, 2000, warrants to purchase 312,500 common shares at an exercise price of $4.00 per share were outstanding. The warrants expired in September 2001.

(I) PER SHARE AMOUNTS

The following table summarizes the basis for the determination of the basic and diluted per share amounts:

	2002	2001
Weighted average shares outstanding *(000s)*	**19,716**	18,593
Effect of dilutive stock options *(000s)*	**368**	427
Weighted average diluted common shares outstanding *(000s)*	**20,084**	19,020
Net earnings per common share		
Net earnings	**5,907**	7,607
Basic *($/share)*	**0.30**	0.41
Diluted *($/share)*	**0.29**	0.40
Cash flow from operations per common share		
Cash flow from operations	**26,829**	27,578
Basic *($/share)*	**1.36**	1.48
Diluted *($/share)*	**1.34**	1.45

During 2002, 359,000 stock options were anti-dilutive and were omitted from the weighted average diluted common shares outstanding calculation (2001: 746,000).

(J) REDUCTION OF STATED CAPITAL

The Company eliminated the accumulated deficit as at December 31, 2000, by reducing stated capital as ratified by shareholders at the May 18, 2000 Annual General and Special Meeting.

7. INCOME TAXES

The differences between the expected income tax provision based on the combined federal and provincial statutory tax rate of 42.6% (2001: 42.9%) and the amount actually provided is as follows:

	2002	2001
Expected income taxes	**4,321**	5,918
Non-deductible crown payment	**3,119**	3,473
Alberta Royalty Tax Credit	**(248)**	(257)
Resource allowance	**(3,406)**	(3,757)
Rate reduction	**(273)**	(600)
Tax pool adjustments	**252**	950
Other	**(152)**	(35)
	3,613	5,692
Capital taxes	**613**	482
	4,226	6,174

The Company's future income tax liability as at December 31, 2002 is comprised of the following:

	2002	2001
Property, plant and equipment having different income tax and accounting basis	**32,896**	24,622
Future site restoration costs	**(1,297)**	(1,007)
Share issuance costs	**(205)**	(199)
	31,394	23,416

8. COMMITMENTS

Real is committed to payments under operating leases for office space, computer hardware, software licence agreements and vehicles as follows:

2003	435
2004	334
2005	281
2006	268
2007	268
	1,586

9. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the consolidated balance sheet consist of accounts receivable, accounts payable, accrued liabilities and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not be necessarily indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of accounts receivable, accounts payable, accrued liabilities and long-term debt approximate their fair market value.

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

(A) INTEREST RATE CONTRACTS (NOTE 5)

If the interest rate contracts were closed out at December 31, 2002, there would be no material gain or loss recorded.

(B) COMMODITY PRICE AND FOREIGN EXCHANGE HEDGES

The Company uses derivative financial instruments to manage its foreign currency and commodity price exposure. These financial instruments are entered into for hedging purposes only. If the Company were to close out its commodity and foreign exchange contracts at December 31, 2002, it would have paid U.S. $1.0 million, Cdn $0.2 million and Cdn $0.2 million on its oil contracts, foreign exchange contracts and natural gas contracts respectively.

i) Oil

Swaps

Volume	WTI Price	Term
200 barrels per day	U.S. $24.90	April 1, 2002 to March 31, 2003
350 barrels per day	U.S. $24.90	July 1, 2002 to June 30, 2003
500 barrels per day	U.S. $25.50	January 1, 2003 to September 30, 2003

Collars

Volume	WTI Price	Term
200 barrels per day	U.S. $23.00 to U.S. $26.75	April 1, 2002 to March 31, 2003
500 barrels per day	U.S. $20.00 to U.S. $29.65	July 1, 2002 to June 30, 2003

Put option

Volume	WTI Price	Term
1,300 barrels per day	U.S. $20.00	January 1, 2003 to June 30, 2003

ii) Foreign Currency

Forward Contracts

Amount	Rate	Term
U.S. $2.3 million	U.S. $1.00 = Cdn $1.5360	August 1, 2002 to March 31, 2003
U.S. $6.3 million	U.S. $1.00 = Cdn $1.5380	August 1, 2002 to June 30, 2003
U.S. $3.5 million	U.S. $1.00 = Cdn $1.5772	January 1, 2003 to September 30, 2003

iii) Natural Gas

Participating Swap

Volume	AECO Price	Term
1,500 gigajoules per day put		
750 gigajoules per day call	Cdn $4.60	November 1, 2002 to October 31, 2003

Collar

Volume	AECO Price	Term
1,500 gigajoules per day	Cdn $4.00 to Cdn $6.70	November 1, 2002 to October 31, 2003

Put option

Volume	AECO Price	Term
3,000 gigajoules per day	Cdn $4.15	November 1, 2002 to October 31, 2003

The following hedging contracts were entered into subsequent to December 31, 2002.

i) Oil

Swaps

Volume	**WTI Price**	**Term**
250 barrels per day	U.S. $26.85	April 1, 2003 to December 31, 2003
250 barrels per day	U.S. $26.64	July 1, 2003 to December 31, 2003
250 barrels per day	U.S. $27.70	October 1, 2003 to December 31, 2003
500 barrels per day	U.S. $26.37	January 1, 2004 to March 31, 2004

Collars

Volume	**WTI Price**	**Term**
250 barrels per day	U.S. $24.00 to U.S. $28.75	April 1, 2003 to December 31, 2003
250 barrels per day	U.S. $24.00 to U.S. $28.40	July 1, 2003 to December 31, 2003
250 barrels per day	U.S. $24.00 to U.S. $30.35	October 1, 2003 to December 31, 2003
500 barrels per day	U.S. $24.00 to U.S. $28.05	January 1, 2004 to March 31, 2004

ii) Foreign Currency

Forward Contracts

Amount	**Rate**	**Term**
U.S. $3.5 million	U.S. $1.00 = Cdn $1.5464	April 1, 2003 to December 31, 2003
U.S. $2.3 million	U.S. $1.00 = Cdn $1.5315	July 1, 2003 to December 31, 2003
U.S. $1.2 million	U.S. $1.00 = Cdn $1.4965	October 1, 2003 to December 31, 2003
U.S. $2.3 million	U.S. $1.00 = Cdn $1.5100	January 1, 2004 to March 31, 2004

iii) Natural Gas

Swap

Volume	**AECO Price**	**Term**
500 gigajoules per day	Cdn $7.25	March 1, 2003 to October 31, 2003

Collar

Volume	**AECO Price**	**Term**
500 gigajoules per day	Cdn $5.00 to Cdn $10.50	March 1, 2003 to October 31, 2003

Put option

Volume	**AECO Price**	**Term**
3,000 gigajoules per day	Cdn $4.32	February 1, 2003 to October 31, 2003

10. SUBSEQUENT EVENTS

(A) GENERAL PARTNERSHIP

Effective January 2, 2003, the Partnership entered into an asset contribution and assumption of liabilities agreement with each Partner, whereby each Partner transferred to the Partnership its contributed assets and liabilities, all in exchange for Partnership allocations based on the fair market value of the contributions at that date. Subsequent to this date, the Partnership conducts all business that was previously carried on by each Partner.

(B) COMMON SHARE EQUITY OFFERING

On February 27, 2003, the Company announced a common share equity offering for a total of 3.1 million common shares at a price of $4.95 for total gross proceeds of $15.3 million ($14.6 million net of expenses). This offering was subject to regulatory approval and closed on March 21, 2003. Proceeds from the offering will be used to fund the Company's ongoing exploration and development activities and for general corporate purposes.

11. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform with the current year's presentation.

Corporate Information

CORPORATE OFFICE

Suite 700
555 Fourth Avenue S.W.
Calgary, Alberta T2P 3E7
Telephone: (403) 262-9077
Facsimile: (403) 262-6403

DIRECTORS

Martin G. Abbott, LLB (1, 2)
D. Nolan Blades, P.Eng (2, 3)
Frans Burger (1, 3)
Dallas L. Droppo, Q.C.
Lowell E. Jackson, P.Eng (4)
Robert B. Michaleski, C.A. (1)

OFFICERS

Lowell E. Jackson, P.Eng.,
PRESIDENT & CHIEF EXECUTIVE OFFICER

Ken P. Murphy, P.Land,
EXECUTIVE VICE PRESIDENT

Pamela J. Orr, C.A., C.F.A.,
VICE PRESIDENT FINANCE & CHIEF FINANCIAL OFFICER

Frank P. Muller, P.Geol.,
VICE PRESIDENT EXPLORATION

Dallas L. Droppo, Q.C.
SECRETARY

COMMITTEES

Audit Committee (1)
Compensation Committee (2)
Reserve Audit Committee (3)
Environmental, Health & Safety Committee (4)

WEB SITE

www.realres.com

EMAIL

investor@realres.com

LEGAL COUNSEL

Blake, Cassels & Graydon LLP

BANKER

Canadian Imperial Bank of Commerce

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Inc.

AUDITORS

PricewaterhouseCoopers LLP

RESERVE CONSULTANTS

Paddock, Lindstrom & Associates Ltd.

STOCK EXCHANGE

The Toronto Stock Exchange
Trading Symbol: **RER**

TRADING SUMMARY

2002	High	Low	Close	Volume
1st Quarter	$ 4.30	$ 2.90	$ 3.82	3,964,207
2nd Quarter	$ 4.00	$ 3.52	$ 3.85	1,713,207
3rd Quarter	$ 4.00	$ 3.40	$ 3.79	1,103,179
4th Quarter	$ 5.10	$ 3.65	$ 5.10	6,982,977
				13,763,570

ANNUAL GENERAL AND SPECIAL MEETING

You are cordially invited to attend the Annual General and Special Meeting of the Shareholders of Real Resources Inc. which will be held on May 7, 2003, at the Selkirk House Conference Centre on the second floor at 555 – 4th Avenue S.W., Calgary, Alberta, at 3:00 p.m.

If unable to attend, shareholders are requested to complete and return the Proxy form to the Secretary of the Company.

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Our team of talented and experienced individuals is key to our success.

Greg Anderson, Cathy Anton, Renee Arseneau, Linda Boyd, Jane Brezinski, Veda Burby, Terry Butterworth, Paul Case, Tom Charuk, Byron Cooper, Michael Cox, Dale Cugnet, Clay Curry, Lee Davis, Connie Edlund, Colin Flanagan, Larry Green, Dolores Grzelak, Dale Hoff, Jennifer Illaszewicz, Lowell Jackson, Barbara Janz, Kathy Kerby, Patty Kjeldson, Bob Lagimodiere, Allan Larsen, Terry MacGillivary, Jane Mallen, Steve Marston, Erin McKee, Frank Muller, Ken Murphy, Lyle Nakaska, Pamela Orr, Steve Parkins, Dan Petch, Joe Recsky, Daryll Robinson, Tammy Rochon, Kevin Roll, Michael Slezak, Ken Slezina, Mike Stone, Roy Taylor, Kahlil Trotman, Veera Wiber, Zofia Wojcicka.

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